THE ECONOMICS OF ELECTRICITY AND SNG FROM IN SITU COAL GASIFICATION

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Abstract

Conceptual process designs and cost estimates are presented for two potential applications of underground coal gasification: a 900 MW(e) combined-cycle electric generating plant fueled by low-Btu gas, and a substitute natural gas (SNG) plant producing 155 MMscfd of 954 Btu/scf gas. Designs were based on experimental data obtained at the Laramie Energy Research Center on subbituminous coal using the linked vertical well in situ gasification process. Respective capital investments were estimated to be $395 and $351 million in first-quarter 1977 dollars. Product prices were calculated as a function of the debt/equity ratio, the annual earning rates on debt and equity, the cost of coal, and plant factor (onstream efficiency). Using a debt/equity ratio of 70/30, an interest rate on debt of 9%, an after-tax earning rate on equity of 15%, and a coal feed cost of $5/ton, product prices were 24 mills/kWh for electricity at 70% plant factor and $2.89/10^6 Btu for SNG at 90% plant factor. Calculated overall thermal efficiencies for the two facilities were 24 and 38% respectively, based on in-place coal.

Introduction

This paper describes two conceptual plants designed for utilizing gas produced from a linked vertical well (LVW) in situ coal gasification process and gives results of economic evaluations based on the designs. The two plants are a 900 MW(e) combined-cycle electric generating plant fueled by low-Btu gas, and a substitute natural gas plant producing 155 MMscf/day of 954 Btu/scf gas.

The facilities are assumed to be located in southern Wyoming. The design coal is subbituminous. Air injection is used for the low-Btu gas case, and a steam/oxygen mixture for the SNG case.

The two cases presented here are not evaluated as competitors with each other, but are intended to represent two possible modes of utilization of underground coal gasification.

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Linked Vertical Well Process

There are several modes in which the LVW process can be operated for large-scale gas production. These different operational modes arise

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primarily from variations in the well sequencing patterns used, and the direction in which the coal seam is gasified relative to the direction of injection gas and product gas flow. The system illustrated by Fig. 1 is termed the direct-flow or forward system because the direction of gasification of the coal seam is the same as the direction in which the injection gas and product gas travel. (2) The well sequencing pattern that develops is such that each borehole is used successively for linking, production, and injection.

If air is injected, the product is a low-Btu (100 to 200 Btu/scf) gas. The LVW process is also potentially capable of using an injection gas consisting of a mixture of steam and oxygen, in which case the product would be an intermediate-Btu (200 to 400 Btu/scf) gas.

The procedure shown in Fig. 1 was suggested by researchers at the Laramie Energy Research Center (LERC) to be used for development of the field areas of the conceptual plant designs evaluated in this report. It should be pointed out that large-scale operation of this system has not yet been demonstrated at LERC, although it was used by the Russians at the Podmoskovnaya and Shatskaya underground coal gasification stations. In LERC tests to date, reverse combustion linking has been followed by air injection for forward gasification through the same well used for the linking air injection. Steam-oxygen injection has not yet been demonstrated by LERC, but a three-day injection at Hoe Creek by Lawrence Livermore Laboratory (LLL) subsequent to air injection was successful. LERC and LLL work has been completed thus far only in two-well systems.

Process Descriptions and Flow Diagrams

The plants are divided into three major parts: (1) field development, (2) gas transfer piping, and (3) main plant. Well drilling and gasification operations are carried out in the field development areas. The gas transfer piping systems, which may be a mile or two in length, connect the field development areas with the main plant areas. The main plant areas contain the major gas treating process units, power plants, and utilities systems required to form complete, self-sufficient facilities.

Low-Btu Gas Combined-Cycle Electric Generating Plant Case

For this case, the raw low-Btu gas from the wells is cleaned, compressed, and burned in gas turbines connected to electrical generators. Hot exhaust gases from the turbines are directed to heat-recovery boilers to generate 1000 psig/1000°F steam which drives turbine generators for additional electricity production.

At design throughput [900 MW(e)], 48 producing wells are on-line. These 48 wells are arranged in six parallel trains of eight wells each. Each train requires eight injection wells and eight linking wells, so that a train consists of a total of 24 wells.

Field development plan

Initial production starts with only one train of wells. The remaining five trains are brought on-line at intervals of roughly two weeks. A well has a producing lifetime of about 73 days. As each row of wells is exhausted, the train is moved to the next adjacent row. For a given train, these moves occur at 12-week intervals. Since there are six trains, a move takes place every two weeks. Shortly after the sixth train is brought on stream, the first train is shut down. During the ensuing 14 days, the field equipment and piping used by the first train are disconnected, moved, and reconnected to the next row of wells, and production from this train is resumed. Each of the six trains follows this same cyclic pattern of relocation.

Process flow description

Figure 2 shows the block flow diagram for the electricity generating case. The facility consists of the following sections:

Plant Section No.	Process Unit
1	Field development area
2	Raw gas gathering and gasification air transfer piping
3	Heat exchange and raw gas scrubbing
4	Stretford sulfur plant
5	Electric generating plant
6	Stack, cooling towers, water plant, waste water treating, and oil recovery plants

Compressed air is piped from the main plant area about one mile to the field development area, where it is injected into the coal seam. Air for the linking process is supplied by a mobile field-located compressor.

Raw gas is piped to the main plant area for cleaning and removal of sulfur-bearing compounds before being burned to generate electricity. The raw gas is cooled by humidification to condense about 90% of the oil, which is transferred to an oil recovery system, and is cleaned of remaining particulate matter and oil in venturi scrubbers. The scrubbed raw gas is cooled before going to Stretford treating plants, where the H_2S content is reduced to less than 100 ppm by volume.

Treated gas (fuel gas) from the Stretford units is compressed, heated by exchange with the raw gas, burned, and expanded through gas turbines which drive the electric generators, combustion air compressors, and fuel gas compressors. About 2/3 of the electric generating capacity is provided by the gas turbine generators. The remaining 1/3 is provided by steam turbines using waste heat from the exhaust gases. Part of the steam is used to drive the gasification air compressors and other auxiliary equipment.

Design of the combined-cycle electric generating plant is based on information appearing in Energy Conversion Alternatives Studies (ECAS) reports. (3)(4) This was supplemented by information supplied for a similar system which was proposed for use with low-Btu gas. (5) The resulting combined-cycle plant developed for this evaluation was assumed to have a net efficiency of 42%.

Substitute Natural Gas (SNG) Production Case

In the SNG case, raw intermediate-Btu gas from the wells is cleaned, compressed, and fed to CO shift reactors to adjust the CO/H_2 ratio for the methanation reaction. After shifting, H_2S and CO_2 are removed. The resulting sweet gas is methanated, compressed, and dried to final product specifications.

At design throughput (155 MMscf/day of 954 Btu/scf gas) 60 producing wells are on line. These are arranged in six parallel trains of 10 wells each. Each train also requires 10 injection wells and 10 linking wells, so that a train consists of a total of 30 wells. The arrangements of trains in a field development area and of the injection, linking, and producing wells for a single train are similar to those of the electricity generating case. Field development also is similar.

Process flow description

Figure 3 shows the block flow diagram for the SNG case. The plant consists of the following sections:

Plant Section No.	Process Unit
1	Field development area
2	Raw gas gathering, oxygen, and steam transfer piping
3	Heat exchange and raw gas scrubbing
4	CO shift
5	Oxygen plant
6	Benfield HiPure plant
7	Methanation
8	Fuel gas treating
9	Stretford sulfur plant
10	Oil recovery and waste water treating
11	Steam generator and offsites

Oxygen and steam are piped separately from the main plant to the field. The oxygen and steam are mixed at the wellheads for injection into the coal seam.

Raw gas is piped to the main plant area, cooled by heat exchange, humidified, and scrubbed as in the previous case.

After scrubbing, the raw gas is separated into two streams. One stream goes to a DEA treating unit for acid gas removal and subsequent use as a fuel gas. The other stream is cooled and compressed to 450 psia for further processing into SNG product.

After compression, the gas is heated by exchange with the raw gas and sent to the CO shift unit, where it is shifted to an H_2/CO ratio of about 3. After heat recovery and cooling the shifted gas goes to the Benfield HiPure unit. Acid gas from the Benfield unit is piped to the Stretford sulfur plant.

Treated gas from the Benfield unit is heated and proceeds through zinc oxide guard beds, which remove the last traces of H_2S.

Methanation is carried out in a series of three fixed-bed catalytic reactors. Reaction temperature is controlled by a combination of heat recovery and hot product gas recycle.

After methanation, the gas is cooled, compressed, and dehydrated in a triethylene glycol drying unit to meet pipeline gas specifications.

Utilities Systems

The major utilities systems for the two plants include steam, electric power, fuel gas and oil, and cooling water. Utilities generation and consumption are summarized in Table 1.

Table 1. Utilities summary

	Electricity generation case[a]	SNG case
Steam (lb/hr)	1,032,500	3,668,700
Electricity (kW)	21,000	47,000
Fuel gas and oil (MMBtu/hr)	-	3,710
Purchased water (gpm)	4,350	5,430
Air cooling load (MMBtu/hr)	550	2,260

[a]Utilities consumed in the combined-cycle generating portion of the facility are not included here.

In the electricity generating case, the gasification air compressors consume about 10% of the total energy produced by the facility. An additional 5% is used to meet other plant requirements. Plant electricity requirements were estimated to be about 21 MW.

In both cases, fresh water (raw water) is assumed to be purchased. All other utilities required by the facilities are generated on site. Process cooling is provided both by air and water cooling. Wet cooling towers were used based on the assumption that adequate water supply (about 5000 gpm) would be available. During start-ups when fuel gas will not be available, oil will be used.

Overall Thermal Efficiencies

Overall thermal efficiencies for the conversion of coal to electricity and SNG are shown in Table 2. Efficiencies were calculated as the higher heating value of the products divided by the higher heating value of the in-place coal. In the low-Btu gas combined-cycle case, the electricity produced was credited at 3413 Btu/kWh. The heating value for SNG was taken at 60°F. No thermal credit was taken for by-product sulfur.

Table 2. Overall thermal efficiencies

Product	Overall thermal efficiency (%)
Electricity	24
SNG	38

Basis for Design and Process Assumptions

The design basis for the linked vertical well (LVW) process was developed from experimental results obtained at the Laramie Energy Research Center (LERC). Field test Hanna II, Phase II was used as the basis for operating conditions and yields for the electricity generating case. This test was conducted in the Hanna No. 1 seam of subbituminous coal at Hanna, Carbon County, Wyoming. Because of the lack of published experimental data for the steam-oxygen injection process, the basis for operating conditions and yields for this mode of gasification was a linear permeation mathematical model of forward combustion which was developed at LERC. (6-8) Table 3 shows the process design parameters developed for the two cases.

Table 3. LVW gasification process design parameters

Parameters common to low-Btu and SNG cases	
Type of coal	Subbituminous (Hanna No. 1 seam)
Seam thickness	30 ft
Depth of seam	300 ft
Well pattern and spacing	Square; 150 ft x 150 ft
Gasification reaction zone advance rate	2 ft/day
Process sweep efficiency	80%
Process thermal efficiency	80%
Overall process efficiency	64%
Raw gas wellhead temperature	640°F
Linking air injection pressure	1 psig/ft of depth
Linking air injection rate	33,000 scf/ft of link
Reverse combustion linking rate	7 ft/day
Parameters applicable to low-Btu gas case	
Single well production rate	30 MMscfd
Air injection requirement	73,570 scf/ton maf coal
Dry gas produced/air injected	1.45 scf/scf
Parameters applicable to SNG case	
Single well production rate	17 MMscfd
Steam/oxygen injection gas composition	60/40 mole %
Steam + O_2 injection requirement	23,270 scf/ton maf coal
Dry raw gas produced/steam + O_2 injected	1.92 scf/scf

Capital Investments

Estimated total capital investments for the two conceptual facilities are summarized in Table 4. The capital investments do not include the cost of the coal (or land and mineral rights) required for the facilities. Coal is charged to the facilities as a raw material as part of the operating costs. The cost, in $/ton, is treated as a variable in the economic calculations.

Table 4. Capital investment summary

Capital investment for plant sections	Capital Investment, $\$10^6$ 900 MW(e) plant	SNG plant
Site development	1.8	2.1
Initial drilling costs	1.3	1.6
Field gas treating plant	8.6	11.1
Field piping system	11.3	20.3
Raw gas treating plant	17.2	19.0
CO shift plant	-	28.5
Oxygen plant	-	81.5
Benfield plant	-	17.9
Methanation plant	-	28.1
Fuel gas treating plant	-	6.7
Stretford plant	6.5	4.8
Electric generating plant	255.7	-
Tankage, offsites, utilities	10.6	43.5
Total for plant sections	313.0	265.1
Capital investment for facility		
Engineering	8.1	12.9
Construction overhead	7.6	16.5
Contingencies	32.7	29.3
Contractor's fee	9.8	8.8
Special charges	23.8	18.7
Total for facility	82.0	86.2
Total capital investment	395.0	351.3

Initial well drilling and preparation work which occurs during the plant construction period is included in plant capital costs. After the plant is started up, this cost is included as an operating charge.

All costs given here are referenced to first quarter 1977 and are expressed in first quarter 1977 dollars.

Operating Costs

Operating costs include raw materials, catalysts and chemicals, water, other operating supplies and materials, maintenance materials and labor, operating labor and supervision, and general and administrative overhead. They do not include depreciation (recovery of capital), interest on debt, return on investment, or taxes, which are accounted for internally by the overall economics program. Marketing and distribution costs were not included.

The in-place coal cost, in \$/ton, was treated as a variable and was varied parametrically from 0 to \$10/ton.

Field equipment moving expenses are based on moving each train of wells once per quarter. The moving cost was estimated from material and labor costs for the initial installation. Additional quarterly costs for labor and equipment used in moving field systems were \$120,000 and \$135,720 in the electricity generating and SNG cases, respectively.

Operating cost bases are summarized in Table 5. Other assumptions used are as follows:

- Plant operating lifetime: 20 years
- Construction period (pre-operational period): 2 years
- Working capital is 12% of fixed capital investment.
- Maintenance is 4% of depreciable capital per year.
- Plant factor (operating factor) is 70% for electric generating plant, 90% for SNG plant.
- Direct labor rate is $8.25/hr.
- Labor burden is 35% of direct labor.
- Supervision is 15% of labor plus labor burden.
- Operating supplies are 30% of direct operating labor.
- Overhead is 135% of labor plus supervision.
- Federal income tax rate is 48%.
- State income tax rate is 3%.
- Local taxes and insurance are 3% of capital per year.

Table 5. Operating cost basis

Coal	Low-Btu Gas	SNG
Coal used (in-place basis) at 100% plant factor:		
tons/day	18,073	22,951
10^6 tons/yr	6.60	8.25
Drilling:		
Depth of holes (ft)	300	300
Drilling cost ($/ft)	30	30
Number of wells/yr[a]	144/212/100	180/270/150
Operating labor:		
Men/shift	48	45
Catalysts and chemicals at 100% plant factor:		
(10^6 $/yr)	0.217	4.235
By-product sulfur:		
(long tons/day)	29	38

[a]Final year of construction/first through next-to-last operating year/last operating year.

Economic Analysis

Prices of electricity and SNG were calculated as a function of coal cost and annual after-tax rate of return on equity capital. This was done by the discounted cash flow procedure for two capital structures, 100% equity and 70/30 debt/equity. Annual after-tax rate of return on equity was treated as a parameter using rates of return of 10, 12, 15, and 17%. Annual interest rate on debt was assumed to be 9%. By-product credit was included for sulfur at $60/long ton. A computer program was used for these calculations. (9)

The resulting product prices are highly dependent on the capital structure and plant factor. Typical examples are shown in Table 6 and Fig. 4.

Table 6. Estimated product prices[a] at 15% return on equity[b] and 9% annual interest rate on debt

Coal Price ($/ton)	Product price for electricity from low-Btu gas[c] (mills/kWh)		Product price for SNG[d] ($/$10^6$ Btu)	
	100% equity	70/30 D/E	100% equity	70/30 D/E
0	31.4	19.4	3.34	2.13
5	35.6	23.6	4.11	2.89
10	40.0	27.7	4.87	3.66

[a]Product transportation, distribution, and marketing costs are not included.

[b]Annual after-tax rate of return on equity.

[c]70% plant factor.

[d]90% plant factor.

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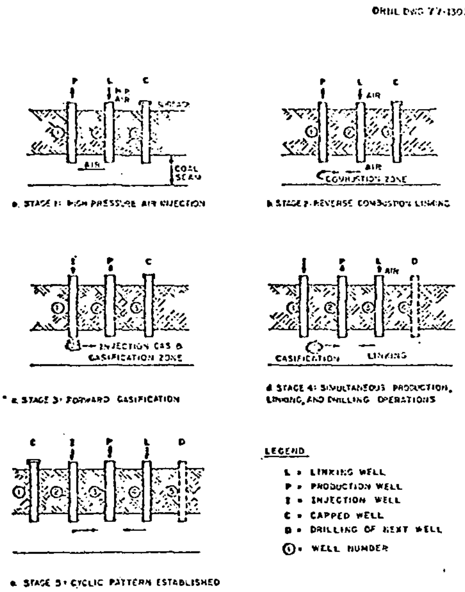

Fig. 1. Stages in the field development of the linked vertical well process

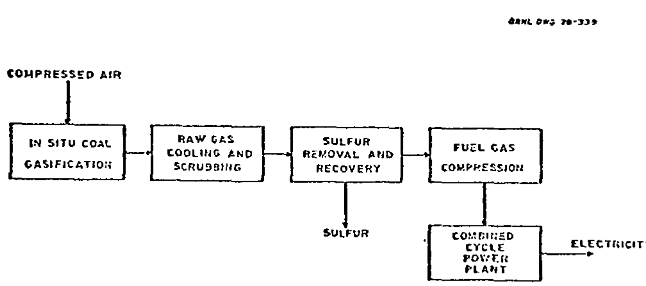

Fig. 2. Block flow diagram for electricity generating case

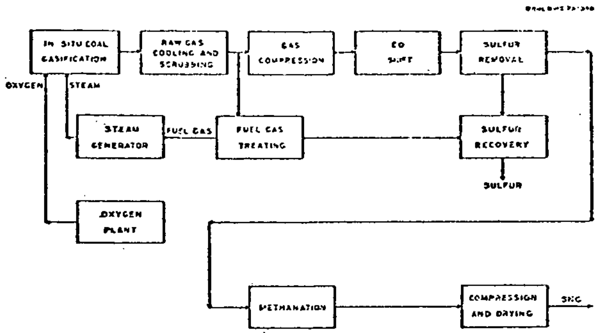

Fig. 3. Block flow diagram for SNG case

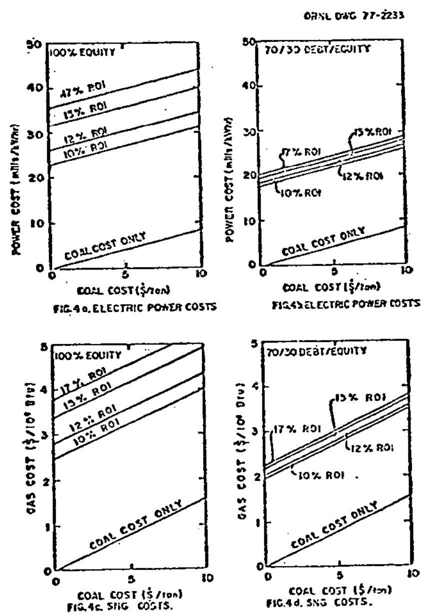

Fig. 4. Electric power and SNG costs